# 2011 IRP Sales and Load Forecast

## Average Load

The 2011 IRP average system load forecast is lower initially than the 2009 IRP average system load forecast. However, after 2015, the 2011 IRP forecast is higher in all remaining years of the forecast period . The recovery in the national and service-area economy is expected to cause load growth to steadily revive. In addition, the lowered expectations in existing and committed energy efficiency measures, combined with retail electricity prices that incorporate much-reduced impact of carbon on Idaho Power's retail electricity prices, result in an increase of forecast average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The retail electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast* in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected cost of carbon emissions. When compared to the electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast*, the 2009 IRP price forecast yielded significantly higher future electricity prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions. The carbon assumptions from the 2006 IRP is the driver for the 2011 IRP's retail electricity price forecasts.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials planned to begin operation in January 2011 and will reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power retail customers. Both factors resulted in a higher long-term load forecast than was used in the 2009 IRP. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to recover; and by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).
- In this year's forecast, an additional customer referred to in this document as "Special" was included in the Additional Firm Load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this

forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the Additional Firm Load category.

- There continues to be significant uncertainty associated with the growth of new industrial and special contract customers and their potential impact on the load forecast. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area and the unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron's residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the IRP load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the IRP load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast is expected, compared to earlier forecasts (prior to the 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). Higher farm commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.

## Peak-Hour Demands

Peak day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- This year's peak forecast also reflects the increased expected peak demand of an additional "Special" contract customer. The anticipated peak load of the new contract has been included in this year's forecast based on discussions with the interested parties.
- The 2011 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs selected for implementation since 2001. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2011 IRP peak demand forecast model does not consider or adjust for the impact of demand response programs. The demand response programs are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model allows peaks to be calculated at the 50th, 90th, and 95th percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the 100th percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model regressions.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. The median peak day temperature has a 50-percent probability of being exceeded. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures. The weighted average peak day temperature drivers are calculated over the 1980–2009 time period (the most recent 30 years).

This page left blank intentionally.

# Overview of the Forecast

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special contract customers, including Micron Technology, Inc., (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, one additional high-probability special contract customer (referred to as "Special"), and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These six, special contract customers are combined into a single forecast category labeled Additional Firm Load. In the 2009 IRP sales and load forecast, the "Special" contract load was combined with the industrial sector (Schedule 19) load forecast. Given the magnitude of their expected future load, the "Special" contract has now been combined with the other larger special contract customers that have monthly metered demands greater than 20,000 kilowatts (kW). Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as they are billed, it is necessary to adjust these billed sales to the proper timeframe to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual-average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2011 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space heating demand that normally occurs in December, January, or February; and 2) a larger, summer-peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak day temperatures, historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River are forecast based on historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

## Fuel Prices

Fuel prices, in combination with service area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2011–2030)**
*(average annual percent change)*

| | Nominal | Real* |
|---|---|---|
| Electricity–2011 IRP–Carbon | 2.6% | 0.9% |
| Electricity–2009 IRP–Carbon | 5.1% | 3.2% |
| Natural Gas | 2.5% | 0.8% |

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2010 and over the forecast period 2011–2030. Both nominal and real prices are shown. In the 2011 IRP carbon scenario, nominal electricity prices are expected to slowly climb to nearly 13 cents per kilowatt-hour (kWh) by the end of the forecast period in 2030. Real electricity prices (inflation adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 0.9 percent each year. In the 2009 IRP electricity price carbon scenario, nominal electricity prices were assumed to climb to nearly 22 cents per kWh by 2030, and real electricity prices (inflation adjusted) were expected to increase over the forecast period at an average rate of 3.2 percent each year. The impact of the much higher electricity price forecast on the 2009 IRP load forecast was significant and served to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions.

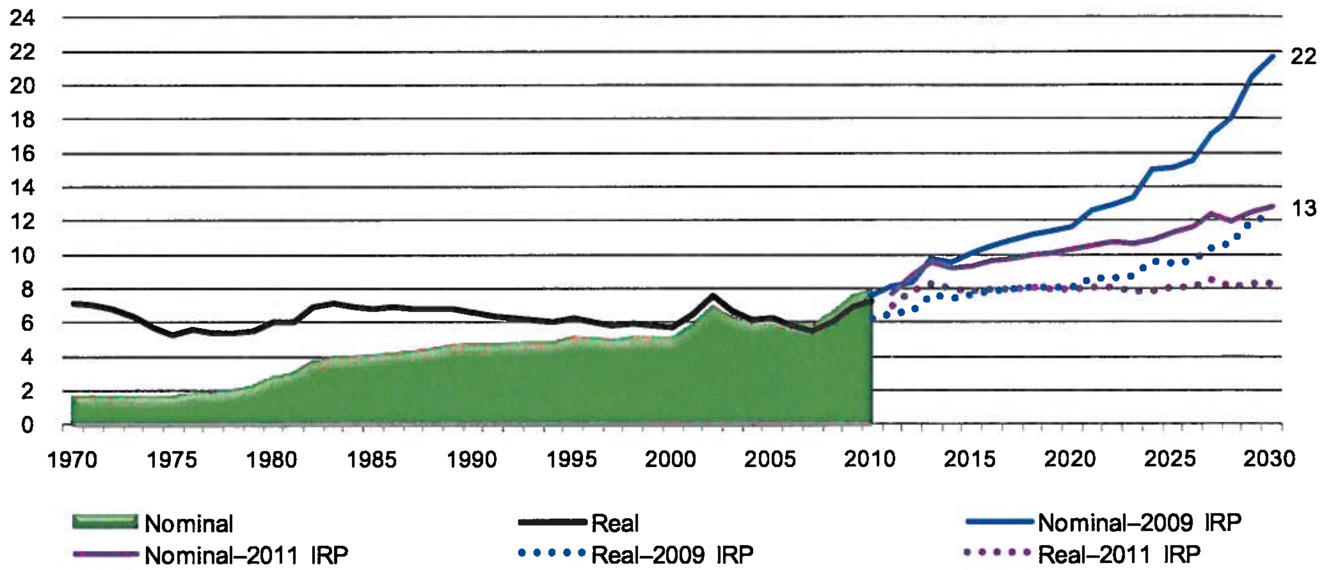


**Figure 1. Forecasted electricity prices**
*(cents per kWh)*

Electricity prices for Idaho Power customers moved significantly higher in 2001 and 2002 because of the Power Cost Adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2009, and forecast prices from 2010–2030. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before again moving sharply upward in 2004, 2005, and 2006. Natural gas prices moved downward in 2010, reflecting the collapse in natural gas prices that began in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise in 2011, plateau through 2014, and then slowly rise throughout the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2009, growing at an average rate of 2.5 percent per year over the forecast period (2011–2030). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.8 percent each year.

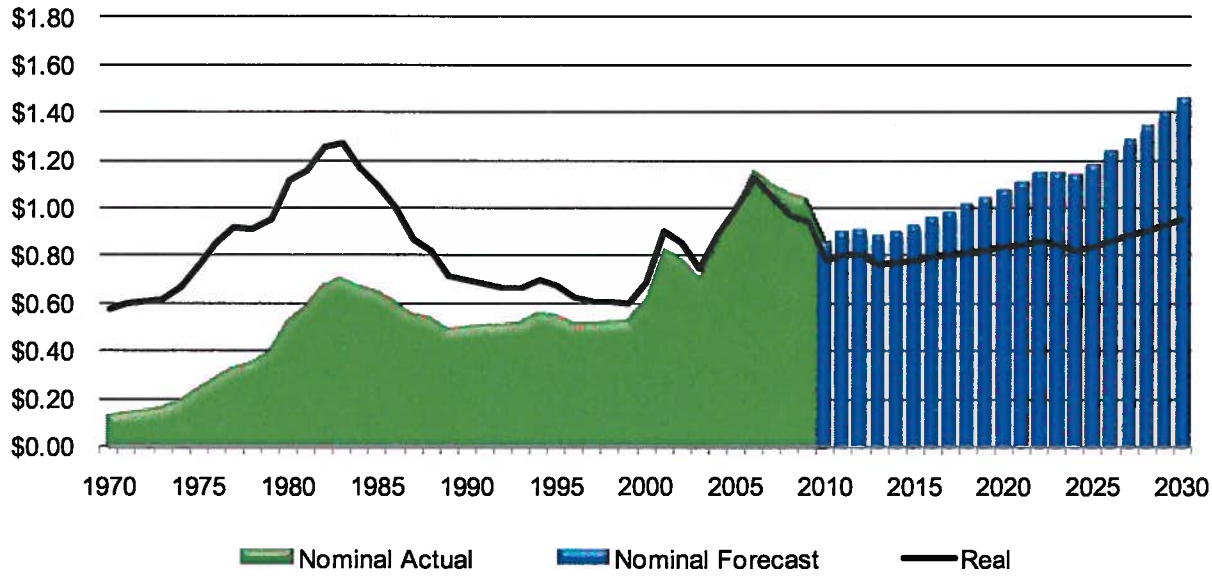


**Figure 2. Forecasted residential natural gas prices**
*(dollars per therm)*

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2011 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

With the anticipated introduction of electric vehicles in December 2010 from General Motors and Nissan, Idaho Power includes a forecast of the potential load impact associated with customer needs for battery recharging. Without the benefit of actual consumer adoption data and clarity on charging infrastructure composition, the forecast methodology relies on previous modeling efforts from EPRI[1] and Oak Ridge National Laboratory[2] drawing on their forecasts of the electric-vehicle market share and charging usage and loads. The assumptions of these and other early forecasts were made without benefit of empirical vehicle performance attributes, such as vehicle battery capacity, pricing, actual consumer adoption behavior, and other salient marketing variables. Since these variables represent primary economic determinants of electric-vehicle adoption, the early forecasts are subject to potentially high degrees of revision. Other determinant variables, such as gasoline price, exhibit high degrees of volatility that add to the wide range of potential adoption outcomes.

The Oak Ridge study assumed a 25 percent electric-vehicle share of new vehicle registrations by 2020 and thereafter held constant. The EPRI study relied on year 2050 share scenarios that ranged from 20 percent to 80 percent. Their medium range forecast for 2020 was approximately 35 percent. After evaluating historical rates of adoption of new transportation technology, particularly those associated with fuel-efficient diesel engine adoption in Europe, the Idaho Power model was based on a

[1] Environmental Assessment of Plug-In Hybrid Electric Vehicles, July, 2007.

[2] Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation, January, 2008.

40-percent share by 2050 with annual adoption growth rate associated with diesel-technology adoption. The resulting Idaho Power forecast share of electric vehicles of new, light-duty vehicles registered in Idaho Power's service area is approximately 12 percent in 2020 and 26 percent in 2030. These rates were applied to a forecast of new, light-duty vehicle registrations for Idaho Power's service area using base-case assumptions from Moody's Analytics, Inc.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption for the purposes of improving the forecasting model in future forecasts.

Figure 3 illustrates the increase in loads expected from the roll-out of electric vehicles over 2010–2030. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, the residential sector representing the greatest impact.

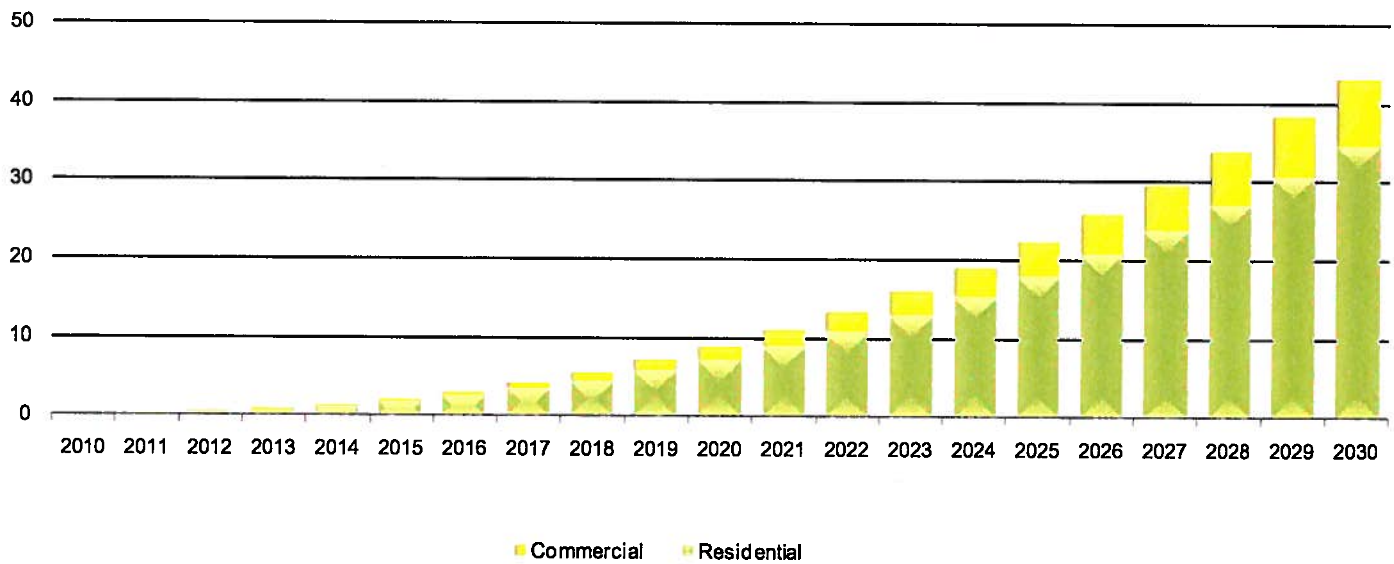


**Figure 3. Electric vehicles**
*(aMW)*

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected-case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

The expected-case load forecast assumes median temperatures and median precipitation, i.e., there is a 50 percent chance that loads will be higher or lower than the expected-case loads due to colder-than-median or hotter-than-median temperatures, or wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December over the 1980–2009 time period (the most recent 30 years) was 1,036. The 70$^{th}$ percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90$^{th}$ percentile HDD is 1,291 and would be exceeded in one-out-of-ten years. The 100$^{th}$ percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$ percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$ percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$ percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume that temperatures and precipitation would maintain a 70$^{th}$ percentile or 90$^{th}$ percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70$^{th}$ percentile or 90$^{th}$ percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2011 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak day average temperatures. The probability associated with each individual peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

| Scenario | Weather Probability | Probability of Exceeding | Weather Driver |
|---|---|---|---|
| **Forecasts of Average Load** | | | |
| 90$^{th}$ Percentile | 90% | 1-in-10 years | HDD, CDD, GDD, Precipitation |
| 70$^{th}$ Percentile | 70% | 3-in-10 years | HDD, CDD, GDD, Precipitation |
| Expected Case | 50% | 1-in-2 years | HDD, CDD, GDD, Precipitation |
| **Forecasts of Peak Demand** | | | |
| 95$^{th}$ Percentile | 95% | 1-in-20 years | Peak Day Temperatures |
| 90$^{th}$ Percentile | 90% | 1-in-10 years | Peak Day Temperatures |
| 50$^{th}$ Percentile | 50% | 1-in-2 years | Peak Day Temperatures |

The analysis of resource requirements is based on the 70$^{th}$ percentile average load forecast coupled with the 95$^{th}$ percentile peak-demand forecast to provide a more adverse representation of average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50$^{th}$ percentile) average load forecast and the 90$^{th}$ percentile peak-demand forecast are typically used.

## Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also serve to impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2011–2030 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1985–2009).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted system sales (excluding Astaris) observed between 1985 and 2009. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50-percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50-percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1985–2009). The high- and low-case load forecasts also reflect the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, there is a 10-percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 20-year time period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability that the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, one-year, five-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

| Probability of Exceeding | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 90% | 90% | 90% | 90% |
| Expected Case | 50% | 50% | 50% | 50% |
| High Growth | 10% | 10% | 10% | 10% |

| Probability of Occurrence | | | | |
|---|---|---|---|---|
| **Scenario** | **1-year** | **5-year** | **10-year** | **20-year** |
| Low Growth | 26% | 26% | 26% | 26% |
| Expected Case | 48% | 48% | 48% | 48% |
| High Growth | 26% | 26% | 26% | 26% |

System load includes the sum of residential, commercial, industrial, irrigation, special contracts (including Astaris, historically), and Raft River. Idaho Power system load projections are reported in Table 4 and pictured in Figure 4. The expected-case system load forecast growth rate averages 1.4 percent per year over the 20 years of the planning period. The low scenario projects that system load will increase at an average rate of 1.0 percent per year throughout the forecast period. The high scenario projects load growth of 1.8 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| Low | 1,793 | 1,894 | 1,970 | 2,158 | 1.0% |
| Expected | 1,819 | 1,970 | 2,090 | 2,362 | 1.4% |
| High | 1,878 | 2,094 | 2,271 | 2,642 | 1.8% |

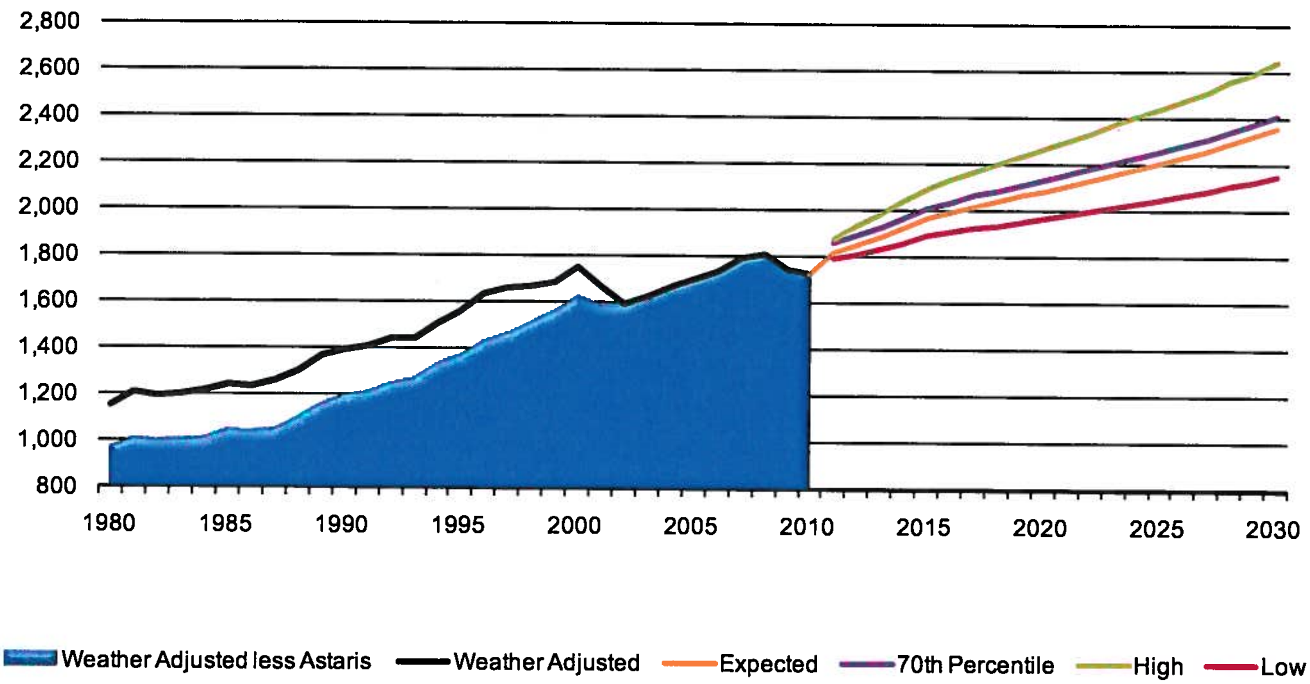


**Figure 4. Forecasted system load**
*(aMW)*

This page left blank intentionally.

# Residential

The expected-case residential load is forecast to increase from 595 aMW in 2011 to 786 aMW in 2030, an average annual compound growth rate of 1.5 percent. In the 70th percentile scenario, residential load is forecast to increase from 611 aMW in 2011 to 810 aMW in 2030, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 5.

**Table 5. Residential load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 646 | 681 | 744 | 860 | 1.5% |
| 70th Percentile | 611 | 644 | 702 | 810 | 1.5% |
| Expected Case | 595 | 626 | 682 | 786 | 1.5% |

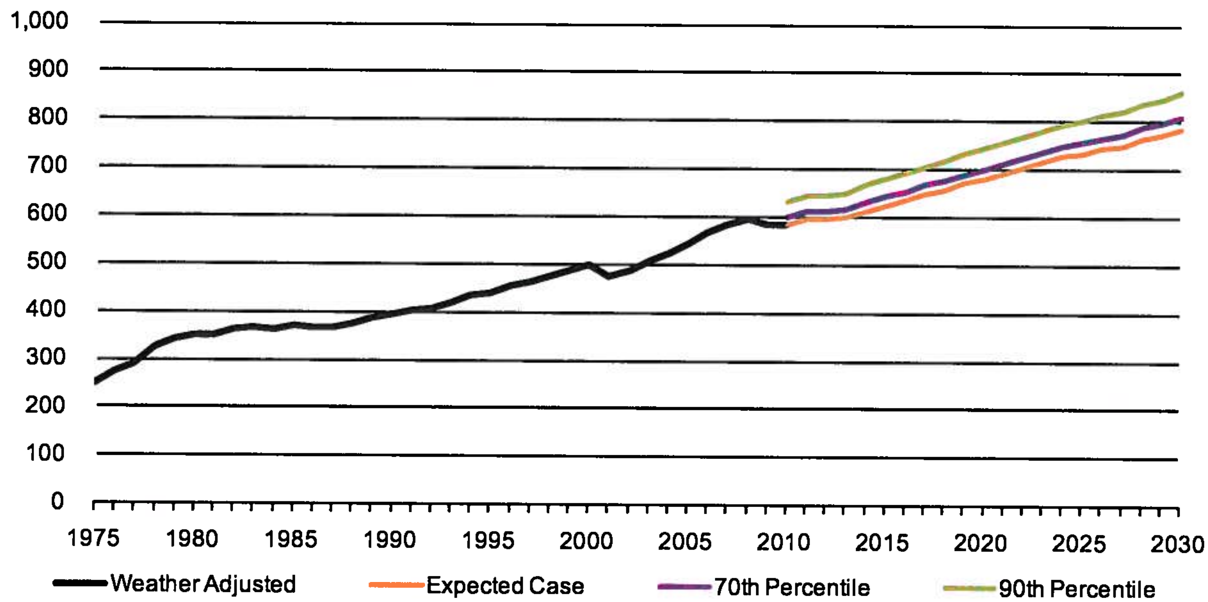


**Figure 5. Forecasted residential load**
*(aMW)*

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1980 and 37 percent of system sales in 2010. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2030. There were 408,754 residential customers as of December 2010. The number of residential customers is projected to increase to approximately 536,000 by December 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average sales per residential customer were nearly 13,000 kWh in 1975. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential-use-per-customer to stabilize and rise through 2007. However, the recession in 2008 and 2009 combined with conservation programs designed to reduce electricity use served to slow the growth in residential-use-per-customer. The average sales per residential customer are expected to slowly rise to approximately 12,900 kWh per year in 2030. Average annual sales per residential customer are shown in Figure 6.

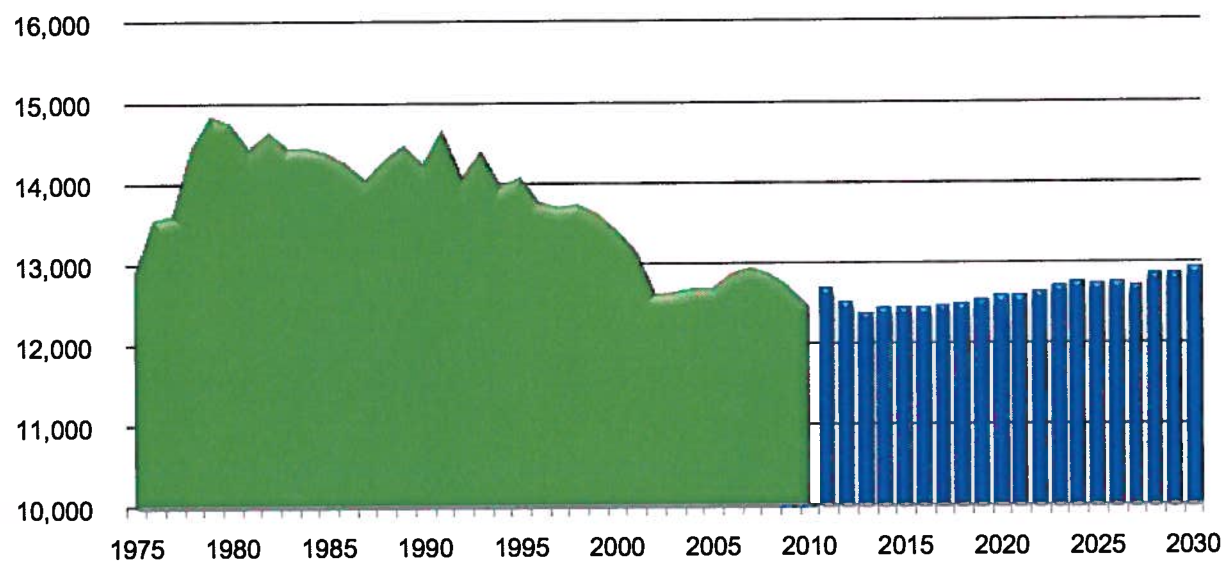


**Figure 6. Forecasted residential-use-per-customer**
*(weather-adjusted kWh)*

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 forecast of county housing stock and demographic data. The residential-customer forecast for 2011–2030 shows an average annual growth rate of 1.4 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics, Inc., forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential-use-per-customer is arrived at by dividing the residential sales forecast, which considers the impact of forecasted DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 439 aMW in 2011 to 561 aMW in 2030. The average annual compound-growth rate of commercial load is 1.3 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 443 aMW in 2011 to 568 aMW in 2030. The commercial load forecasts are illustrated in Figure 7.

**Table 6. Commercial load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 453 | 479 | 504 | 583 | 1.3% |
| 70th Percentile | 443 | 468 | 492 | 568 | 1.3% |
| Expected Case | 439 | 463 | 486 | 561 | 1.3% |

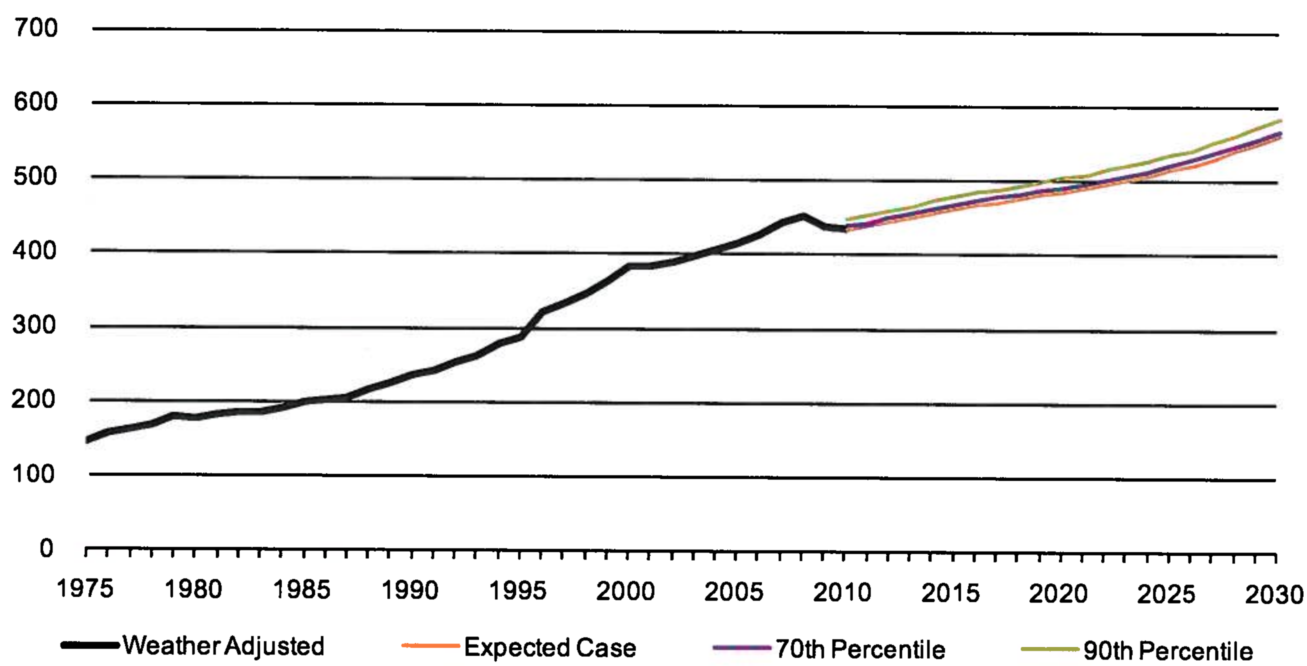


**Figure 7. Forecasted commercial load**
*(aMW)*

As of December 2010, Idaho Power had 64,647 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2 percent, reaching 94,600 customers by 2030. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1980 and nearly 28 percent of system sales in 2010. The commercial customer proportion of system sales is projected to decline to 26 percent of system sales by 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average consumption per commercial customer increased to a record 67,500 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening out over the time period 2010–2011, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 52,400 kWh per customer in 2030. Average annual use per commercial customer is shown in Figure 8.

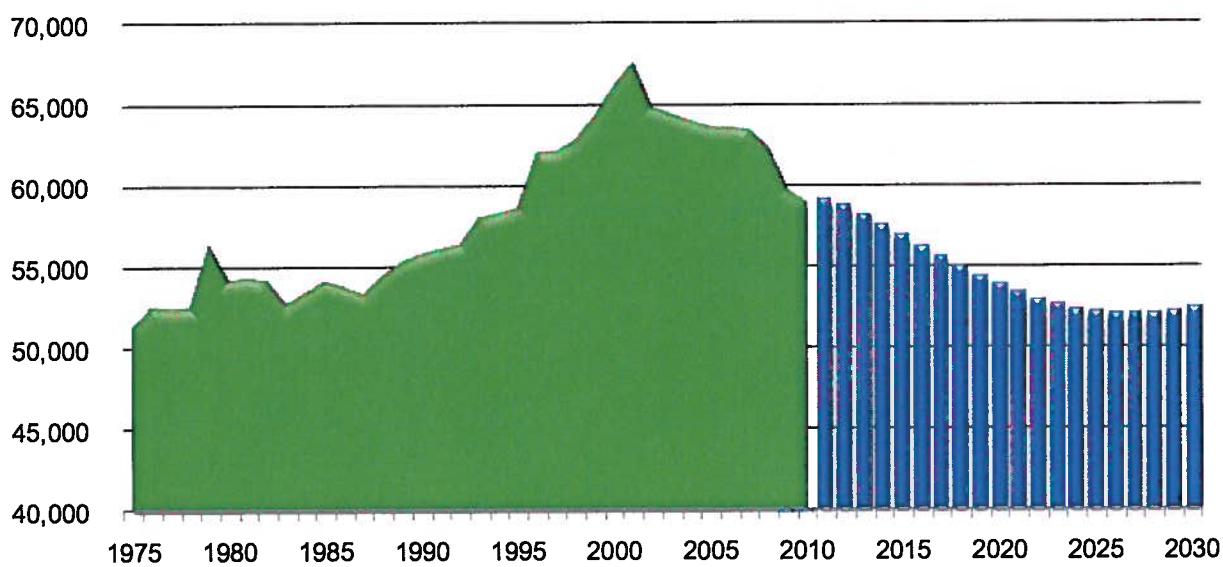


**Figure 8. Forecasted commercial-use-per-customer**
*(weather-adjusted kWh)*

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2011–2030 shows an average annual growth rate of 2 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics, Inc., forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecasted DSM, by the commercial-customer forecast.

# Irrigation

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water-delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly rise from 197 aMW in 2011 to 207 aMW in 2030, an average annual compound growth rate of 0.3 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast slow growth in irrigation load over the 2011–2030 time period. In the 70th percentile scenario, irrigation load is projected to be 213 aMW in 2011 and 223 aMW in 2030. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 9. The figure illustrates the poorer economic conditions and the dramatic reduction in land being put into production that was experienced by the agricultural economy in the mid-1980s.

**Table 7. Irrigation load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90th Percentile | 232 | 234 | 237 | 242 | 0.2% |
| 70th Percentile | 213 | 215 | 217 | 223 | 0.2% |
| Expected Case | 197 | 199 | 202 | 207 | 0.3% |

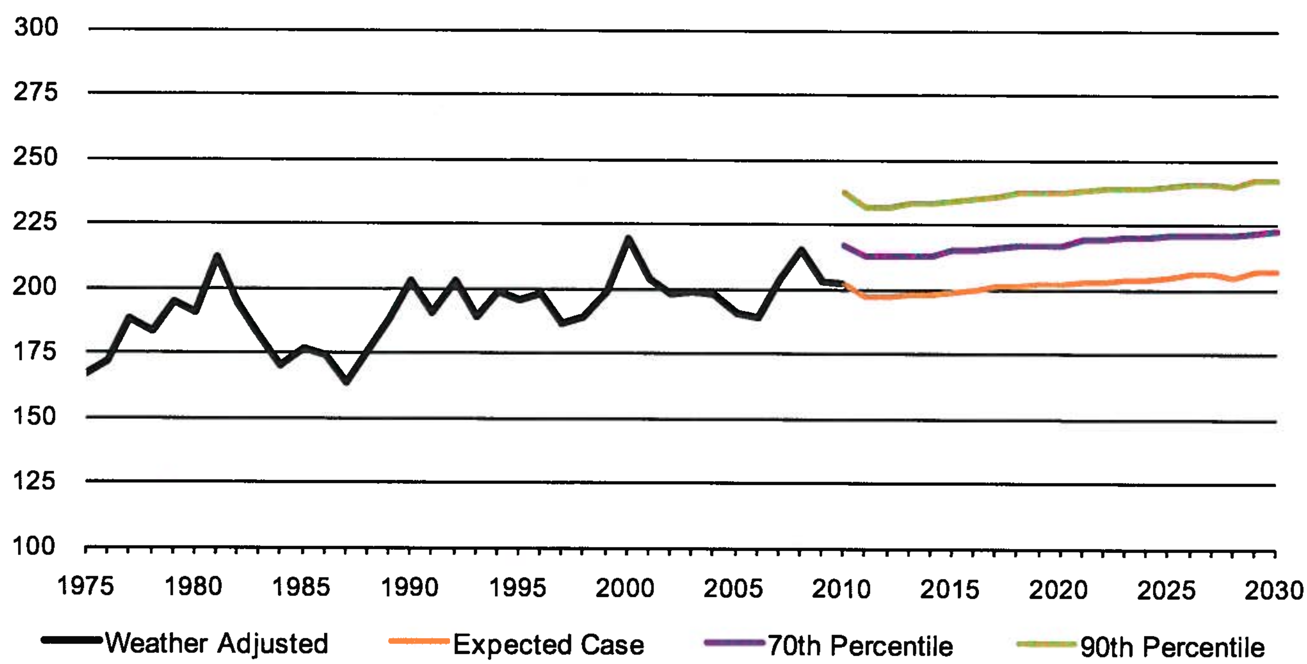


**Figure 9. Forecasted irrigation load**
*(aMW)*

It is important to understand the annual average-load figures reported in Table 7 and graphed in Figure 9 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

The 2011 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce consumption of electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hour (MWh) reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1980. Irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2010, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes. By 2030, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 16.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2010, the number of active irrigation accounts had increased to 17,846 and is projected to be about 23,500 irrigation accounts at the end of the planning period in 2030.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells. In 2007 and 2008, irrigation sales (weather-adjusted) increased by 8 percent and 6 percent, respectively, over each prior year. The increase can be explained, in part, by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh each year.

In the future, factors related to the conjunctive management of ground and surface water, and the possible litigation associated with the resolution, will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

# INDUSTRIAL

The industrial category is made up of Idaho Power's Large Power Service (Schedule 19) customers with monthly metered demands between 1,000 kW and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2010, the number of industrial customers had risen to 121, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 262 aMW in 2011 to 359 aMW in 2030, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 10.

**Table 8. Industrial load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| Expected Case | 262 | 283 | 302 | 359 | 1.7% |

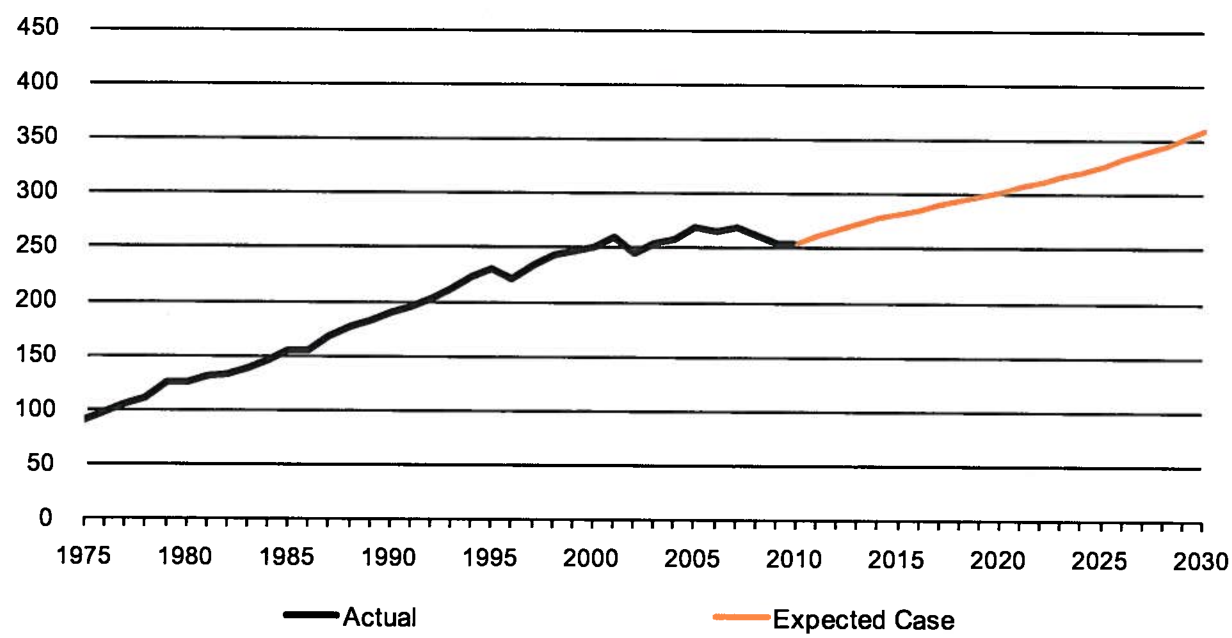


**Figure 10. Forecasted industrial load**
*(aMW)*

The industrial energy forecast is based on the most recent (July 2010) national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 11 illustrates the 2010 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (46 percent); followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (7 percent); Educational Services, Wholesale and Retail Trade, and Health Services (each representing 6 percent); and Other Manufacturing (5 percent). As Figure 11 shows, several other industry groups make up the remaining share of the 2010 industrial electricity consumption.

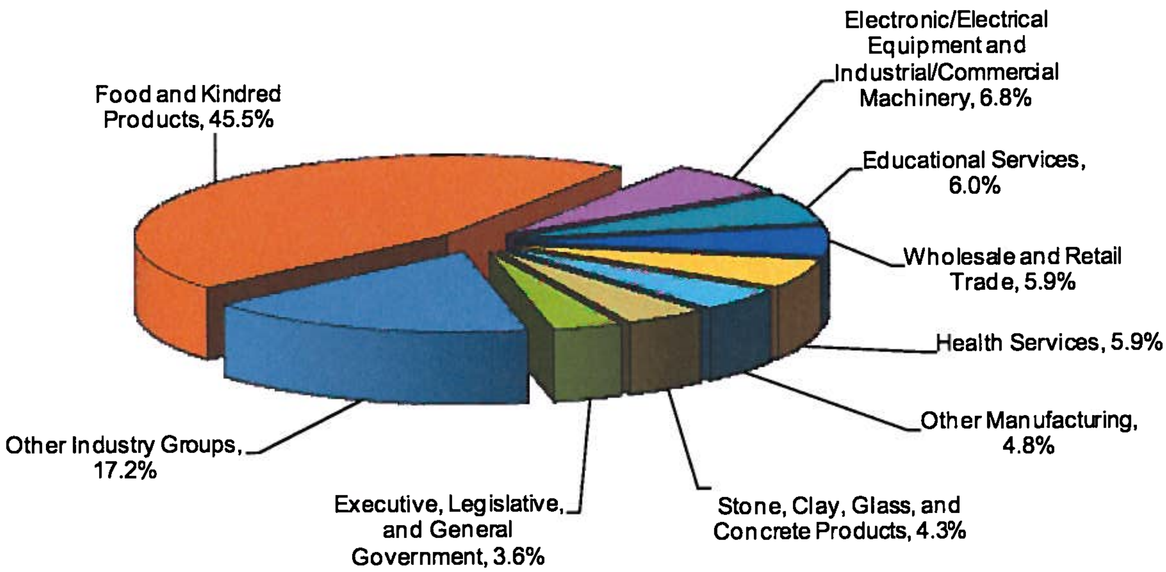


**Figure 11. Industrial electricity consumption by industry group**
*(based on 2010 figures)*

# ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a "special contract" schedule negotiated between Idaho Power and each of these individual large-power customers. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific, cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special contract customers recognized as firm load customers. These special contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered eminent. In this year's forecast, the company has included the anticipated load of an additional special contract customer referred to as "Special" in the additional firm load category, even though a long-term special contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contract customers and the new "Special" contract together make up the additional firm load category.

In the expected-case forecast, additional firm load is expected to increase from 165 aMW in 2011 to 243 aMW in 2030, an average growth rate of 2 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$ percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 12.

**Table 9. Additional firm load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| Expected Case | 165 | 229 | 236 | 243 | 2% |

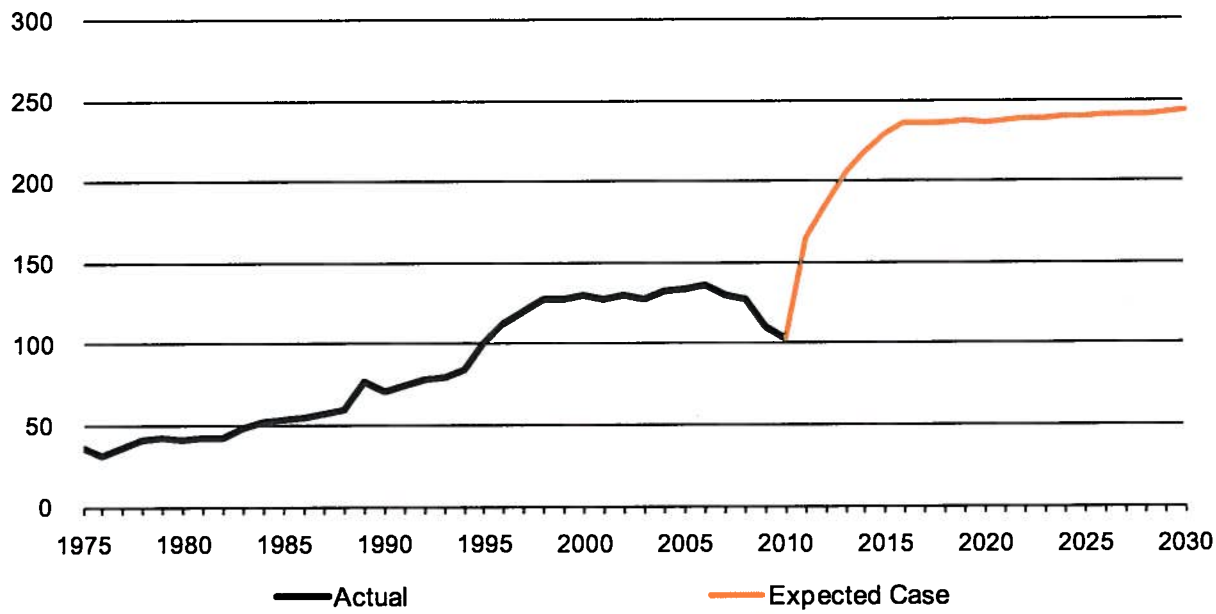


**Figure 12. Forecasted additional firm load**
*(aMW)*

## Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on the market demand for their products.

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing for the Pocatello MSA.

## Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2030 for the INL. The forecast calls for loads to increase considerably through 2014, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. As of October 1994, the INL nuclear reactor no longer generates electricity, consequently, the amount of electricity provided by Idaho Power increased considerably.

## Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2013.

## "Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

## Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. In April 2001, Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. Raft River is located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2010. However, Raft River renewed the agreement for an additional one-year term, which would extend service until September 30, 2011. The load forecasts in the 2011 IRP assume that Idaho Power will continue to provide service to the Raft River area through September 30, 2011.

This page left blank intentionally.

# Company System Peak

System peak load includes the sum of individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically), and Raft River.

The all-time system summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer system peak load growth accelerated over the 10 years ending in 2008 as a record number of residential and commercial customers were added to the system and air conditioning became standard in nearly all new residential homes and new commercial buildings.

In the 90th percentile forecast, total system summer peak load is expected to increase from 3,494 MW in 2011 to 4,870 MW in the year 2030, an average growth rate of 1.8 percent per year over the planning period (Table 10). In the 95th percentile forecast, total system summer peak load is expected to increase from 3,515 MW in 2010 to 4,901 MW in the year 2030. The three scenarios of projected system summer peak load are illustrated in Figure 13. The 2001 summer peak was dampened by the nearly 30 percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth**
*(MW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 95th Percentile | 3,515 | 3,854 | 4,190 | 4,901 | 1.8% |
| 90th Percentile | 3,494 | 3,831 | 4,164 | 4,870 | 1.8% |
| 50th Percentile | 3,334 | 3,657 | 3,973 | 4,643 | 1.8% |

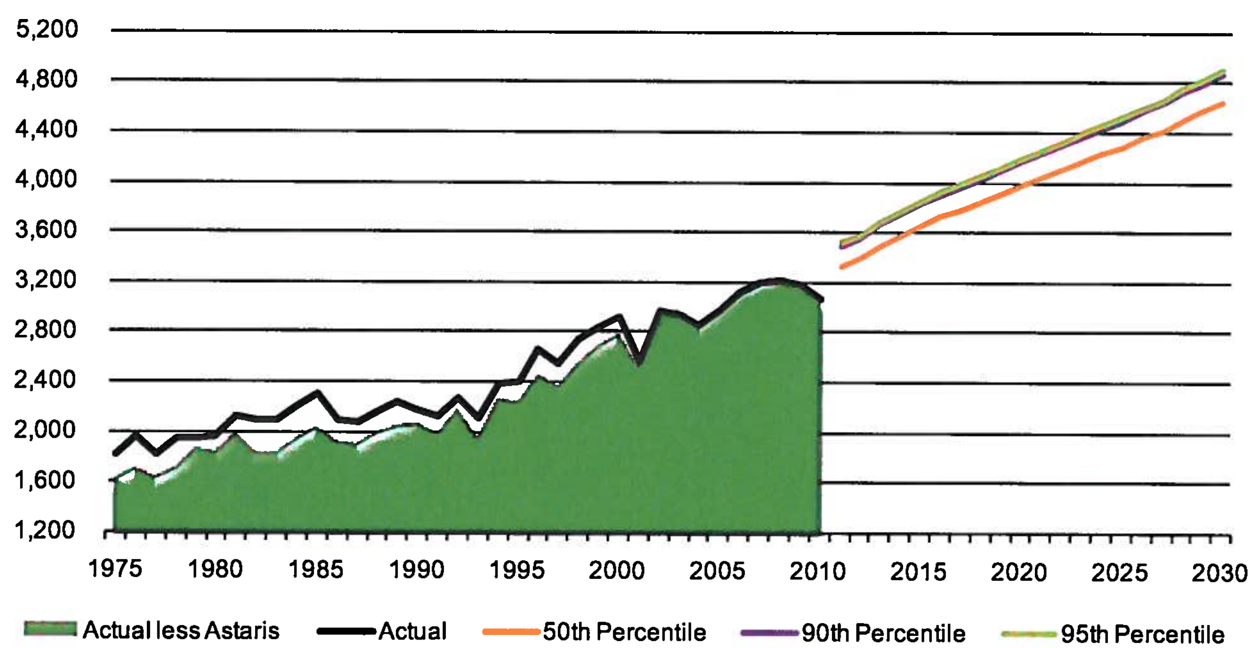


**Figure 13. Forecasted system summer peak**
*(MW)*

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical system winter peak load is much more variable than summer system peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th percentile forecast, total system winter peak load is expected to increase from 2,693 MW in 2011 to 3,336 MW in 2030, an average growth rate of 1.1 percent per year over the planning period (Table 11). In the 95th percentile forecast, total system winter peak load is expected to increase from 2,815 MW in 2011 to 3,509 MW in 2030, an average growth rate of 1.2 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 14.

**Table 11. System winter peak load growth**
*(MW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 95th Percentile | 2,815 | 2,948 | 3,121 | 3,509 | 1.2% |
| 90th Percentile | 2,693 | 2,815 | 2,976 | 3,336 | 1.1% |
| 50th Percentile | 2,384 | 2,478 | 2,604 | 2,896 | 1.0% |

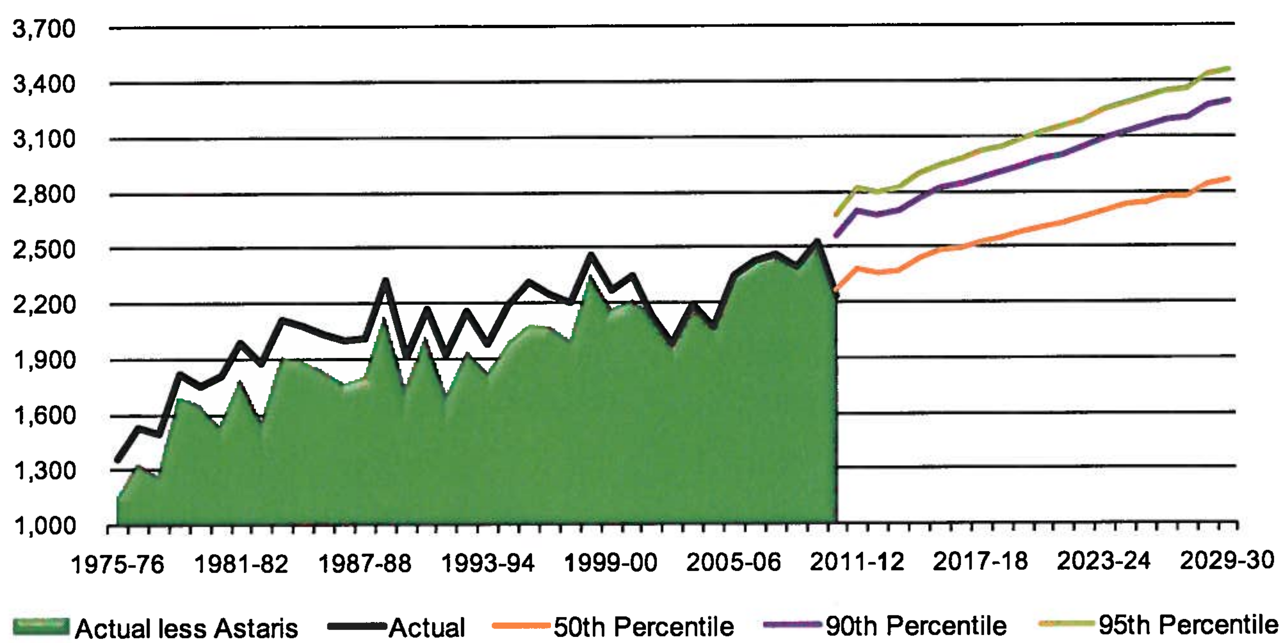


**Figure 14. Forecasted system winter peak**
*(MW)*

# Company System Load

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and Raft River. System load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics, Inc., economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.4 percent per year over the 2011–2030 time period. Company system load projections are reported in Table 12 and shown in Figure 15.

In the expected-case forecast, company system load is expected to increase from 1,819 aMW in 2011 to 2,362 aMW in 2030. In the 70$^{th}$ percentile forecast, company system load is expected to increase from 1,860 aMW in 2011 to 2,414 aMW by 2030, an average growth rate of 1.4 percent per year over the planning period (Table 12).

**Table 12. System load growth**
*(aMW)*

| Growth | 2011 | 2015 | 2020 | 2030 | Annual Growth Rate 2011–2030 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,931 | 2,088 | 2,218 | 2,508 | 1.4% |
| 70$^{th}$ Percentile | 1,860 | 2,013 | 2,136 | 2,414 | 1.4% |
| Expected Case | 1,819 | 1,970 | 2,090 | 2,362 | 1.4% |

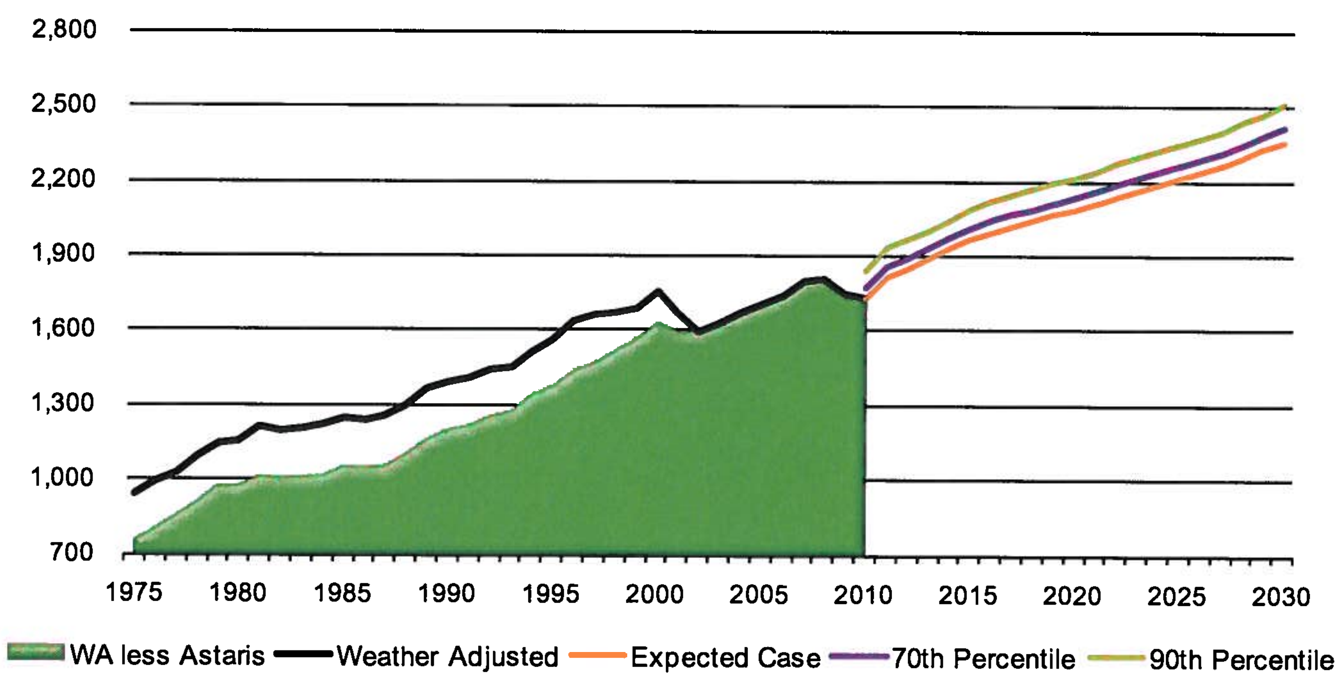


**Figure 15. Forecasted system load**
*(aMW)*

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load excluding Astaris more accurately portrays the underlying general business growth trend within the service area.

# Contract Off-System Load

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

This page left blank intentionally.

# TOTAL COMPANY LOAD

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

The composition of total company electricity sales by year is shown in Figure 16. Residential sales are forecast to be over 32 percent higher in 2030, gaining nearly 1.7 million MWh over 2011. Commercial sales are expected to be nearly 28 percent higher or nearly 1.1 million MWh above 2011 followed by industrial (37 percent higher or nearly 0.8 million additional MWh) and irrigation (only 5 percent higher in 2030 than 2011). Electricity sales to Astaris ended in April 2002.

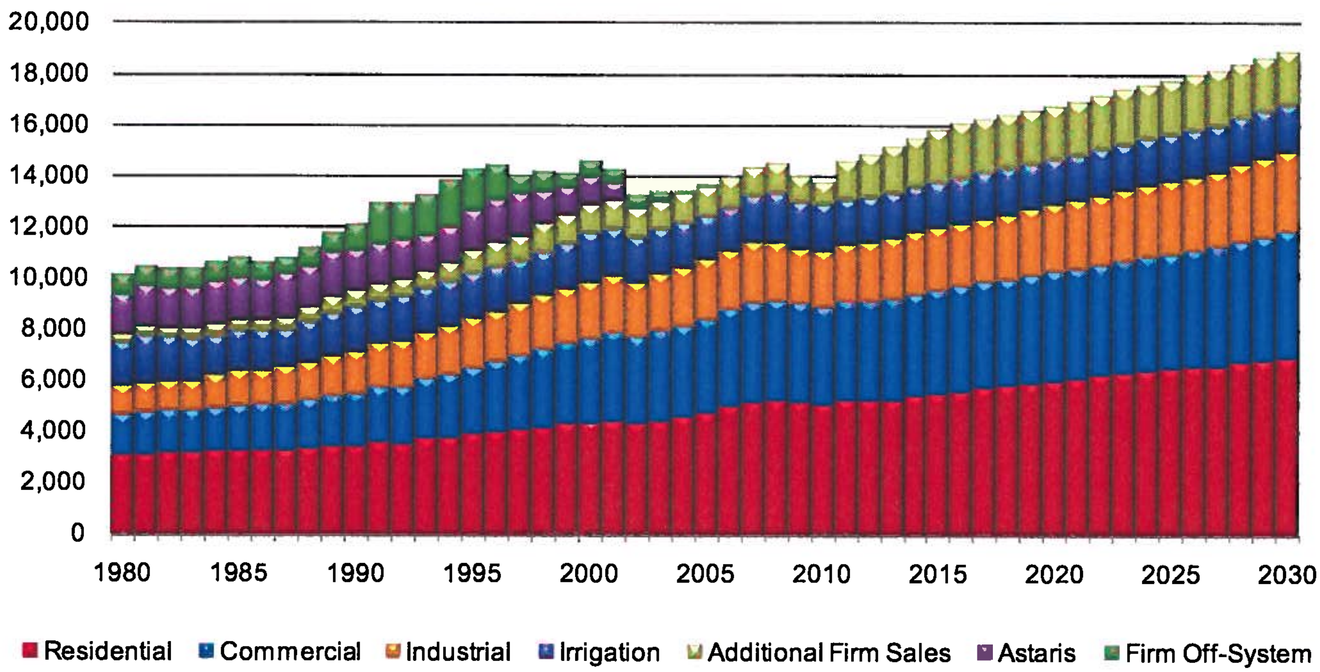


**Figure 16. Composition of total company electricity sales**
*(thousands of MWh)*

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River) is forecast to grow by 47 percent over the 2011–2030 time period, largely due to the addition of Hoku Materials and Idaho Power's newest "Special" contract customer as special contract customers.

This page left blank intentionally.

# DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs that reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are considered in the 2011 IRP *Appendix A–Sales and Load Forecast*; however, demand response programs are accounted for in the 2011 IRP load and resource balance and not in the load forecast. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which were used to develop portfolios for the 2011 IRP.

## Energy Efficiency Programs

The 2011 IRP *Appendix A–Sales and Load Forecast* follows the methodology established in an Itron white paper[3], "Incorporating DSM into the Load Forecast". The authors discussed methods for adjusting load forecasts to account for DSM programs. According to Itron, there are several potential econometric frameworks that can be applied to account for DSM in the forecast period. The methods are designed to adjust the load forecast by accounting for the amount and continuing momentum of the historic DSM contained in the load forecast model.

The "DSM trend" method was chosen as the preferred method to incorporate DSM into the load forecasts for the commercial, industrial, and irrigation sectors. The alternative methods make explicit efforts to adjust DSM out of the history and out of the forecast. The DSM trend takes a different approach by recognizing that historical DSM and DSM trends are embedded in the actual sales data. Forecasting models built on these data implicitly assume that the levels and trends for DSM savings in the history continue into the forecast at approximately the same rate. As a result, the forecast needs to be adjusted only if DSM impacts are expected to be greater or less than the historical trends.

In the final step of the DSM trend method, the forecast is adjusted if the cumulative impacts of past and future programs are expected to accelerate or decelerate relative to the DSM trend line. In this method, the forecast is adjusted up or down by the difference between the DSM trend line and the cumulative impact of past and future programs.

If the total cumulative impact of past and future programs is expected to fall short of the historical trend, then the energy forecast should be adjusted upward by the amount of the deceleration below the DSM trend line.

In another improvement to this year's forecast, Idaho Power used Itron's residential SAE model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process. When applying the SAE framework, DSM activity is naturally incorporated in the efficiency assumptions and the calibration to historic sales data. Efficiency assumptions incorporate national-level DSM impacts. Calibration incorporates specific utility DSM impacts. Therefore, additional adjustments to the residential energy forecast for existing DSM programs were not made.

When using an econometric or SAE model, historical DSM investments influence the historical sales data, the forecast model parameters, and the resulting sales projections. As DSM investment increases,

---

[3] Stuart McMenamin and Mark Quan. "Incorporating DSM into the Load Forecast." Itron , https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

forecasters need to adjust their sales forecasts to account for this acceleration relative to the historic DSM implicitly included in an unadjusted forecast.

The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customers' meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customers' meter.

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

## Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed in *Appendix C–Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2011 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B–Demand Side Management 2010 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

### Residential Load

**Historical Residential Sales and Load, 1970–2010**
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 132,135 | | 9,944 | 1,314 | | 151 |
| 1971 | 138,071 | 4.5% | 10,392 | 1,435 | 9.2% | 165 |
| 1972 | 145,208 | 5.2% | 10,838 | 1,574 | 9.7% | 182 |
| 1973 | 152,957 | 5.3% | 11,501 | 1,759 | 11.8% | 202 |
| 1974 | 160,151 | 4.7% | 12,099 | 1,938 | 10.1% | 224 |
| 1975 | 167,622 | 4.7% | 12,871 | 2,158 | 11.3% | 249 |
| 1976 | 175,720 | 4.8% | 13,544 | 2,380 | 10.3% | 273 |
| 1977 | 184,561 | 5.0% | 13,594 | 2,509 | 5.4% | 288 |
| 1978 | 194,650 | 5.5% | 14,427 | 2,808 | 11.9% | 325 |
| 1979 | 202,982 | 4.3% | 14,821 | 3,008 | 7.1% | 343 |
| 1980 | 209,629 | 3.3% | 14,741 | 3,090 | 2.7% | 352 |
| 1981 | 213,579 | 1.9% | 14,416 | 3,079 | -0.4% | 352 |
| 1982 | 216,696 | 1.5% | 14,627 | 3,170 | 2.9% | 362 |
| 1983 | 219,849 | 1.5% | 14,430 | 3,172 | 0.1% | 366 |
| 1984 | 222,695 | 1.3% | 14,438 | 3,215 | 1.4% | 364 |
| 1985 | 225,185 | 1.1% | 14,375 | 3,237 | 0.7% | 371 |
| 1986 | 227,081 | 0.8% | 14,244 | 3,234 | -0.1% | 368 |
| 1987 | 228,868 | 0.8% | 14,037 | 3,213 | -0.7% | 365 |
| 1988 | 230,771 | 0.8% | 14,282 | 3,296 | 2.6% | 376 |
| 1989 | 233,370 | 1.1% | 14,463 | 3,375 | 2.4% | 386 |
| 1990 | 238,117 | 2.0% | 14,236 | 3,390 | 0.4% | 393 |
| 1991 | 243,207 | 2.1% | 14,654 | 3,564 | 5.1% | 404 |
| 1992 | 249,767 | 2.7% | 14,062 | 3,512 | -1.5% | 405 |
| 1993 | 258,271 | 3.4% | 14,392 | 3,717 | 5.8% | 419 |
| 1994 | 267,854 | 3.7% | 13,957 | 3,738 | 0.6% | 433 |
| 1995 | 277,131 | 3.5% | 14,067 | 3,898 | 4.3% | 440 |
| 1996 | 286,227 | 3.3% | 13,759 | 3,938 | 1.0% | 456 |
| 1997 | 294,674 | 3.0% | 13,692 | 4,035 | 2.4% | 464 |
| 1998 | 303,300 | 2.9% | 13,727 | 4,164 | 3.2% | 475 |
| 1999 | 312,901 | 3.2% | 13,616 | 4,260 | 2.3% | 488 |
| 2000 | 322,402 | 3.0% | 13,409 | 4,323 | 1.5% | 500 |
| 2001 | 331,009 | 2.7% | 13,156 | 4,355 | 0.7% | 476 |
| 2002 | 339,764 | 2.6% | 12,616 | 4,286 | -1.6% | 487 |
| 2003 | 349,219 | 2.8% | 12,639 | 4,414 | 3.0% | 507 |
| 2004 | 360,462 | 3.2% | 12,689 | 4,574 | 3.6% | 525 |
| 2005 | 373,602 | 3.6% | 12,687 | 4,740 | 3.6% | 543 |
| 2006 | 387,707 | 3.8% | 12,872 | 4,991 | 5.3% | 568 |
| 2007 | 397,286 | 2.5% | 12,940 | 5,141 | 3.0% | 585 |
| 2008 | 402,520 | 1.3% | 12,858 | 5,176 | 0.7% | 594 |
| 2009 | 405,144 | 0.7% | 12,696 | 5,144 | -0.6% | 585 |
| 2010 | 407,551 | 0.6% | 12,441 | 5,070 | -1.4% | 582 |

## Residential Load

### Projected Residential Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 411,162 | 0.9% | 12,677 | 5,212 | 2.8% | 595 |
| 2012 | 415,787 | 1.1% | 12,514 | 5,203 | -0.2% | 594 |
| 2013 | 423,098 | 1.8% | 12,350 | 5,225 | 0.4% | 598 |
| 2014 | 432,043 | 2.1% | 12,425 | 5,368 | 2.7% | 614 |
| 2015 | 440,364 | 1.9% | 12,441 | 5,478 | 2.1% | 626 |
| 2016 | 447,754 | 1.7% | 12,425 | 5,563 | 1.6% | 636 |
| 2017 | 454,724 | 1.6% | 12,468 | 5,669 | 1.9% | 648 |
| 2018 | 461,592 | 1.5% | 12,473 | 5,757 | 1.6% | 658 |
| 2019 | 468,394 | 1.5% | 12,530 | 5,869 | 1.9% | 671 |
| 2020 | 475,070 | 1.4% | 12,568 | 5,971 | 1.7% | 682 |
| 2021 | 481,514 | 1.4% | 12,578 | 6,056 | 1.4% | 692 |
| 2022 | 487,734 | 1.3% | 12,627 | 6,159 | 1.7% | 704 |
| 2023 | 493,690 | 1.2% | 12,703 | 6,271 | 1.8% | 717 |
| 2024 | 499,477 | 1.2% | 12,737 | 6,362 | 1.4% | 727 |
| 2025 | 505,167 | 1.1% | 12,722 | 6,427 | 1.0% | 734 |
| 2026 | 510,811 | 1.1% | 12,745 | 6,510 | 1.3% | 743 |
| 2027 | 516,404 | 1.1% | 12,691 | 6,554 | 0.7% | 749 |
| 2028 | 521,918 | 1.1% | 12,851 | 6,707 | 2.3% | 766 |
| 2029 | 527,380 | 1.0% | 12,849 | 6,776 | 1.0% | 774 |
| 2030 | 532,835 | 1.0% | 12,908 | 6,878 | 1.5% | 786 |

## Commercial Load

### Historical Commercial Sales and Load, 1970–2010
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 21,375 | | 42,773 | 914 | | 105 |
| 1971 | 22,077 | 3.3% | 45,388 | 1,002 | 9.6% | 115 |
| 1972 | 22,585 | 2.3% | 46,142 | 1,042 | 4.0% | 120 |
| 1973 | 23,286 | 3.1% | 48,144 | 1,121 | 7.6% | 128 |
| 1974 | 24,096 | 3.5% | 49,027 | 1,181 | 5.4% | 136 |
| 1975 | 25,045 | 3.9% | 51,218 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,512 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,414 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,474 | 1,460 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,389 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,141 | 1,559 | -1.6% | 178 |
| 1981 | 29,567 | 2.7% | 54,282 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,126 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,684 | 1,621 | -0.7% | 186 |
| 1984 | 31,554 | 2.5% | 53,410 | 1,685 | 3.9% | 191 |
| 1985 | 32,417 | 2.7% | 54,076 | 1,753 | 4.0% | 201 |
| 1986 | 33,208 | 2.4% | 53,747 | 1,785 | 1.8% | 203 |
| 1987 | 33,975 | 2.3% | 53,312 | 1,811 | 1.5% | 206 |
| 1988 | 34,723 | 2.2% | 54,432 | 1,890 | 4.4% | 216 |
| 1989 | 35,638 | 2.6% | 55,285 | 1,970 | 4.2% | 226 |
| 1990 | 36,785 | 3.2% | 55,761 | 2,051 | 4.1% | 236 |
| 1991 | 37,922 | 3.1% | 56,076 | 2,127 | 3.7% | 243 |
| 1992 | 39,022 | 2.9% | 56,359 | 2,199 | 3.4% | 253 |
| 1993 | 40,047 | 2.6% | 57,970 | 2,321 | 5.6% | 263 |
| 1994 | 41,629 | 4.0% | 58,246 | 2,425 | 4.4% | 280 |
| 1995 | 43,165 | 3.7% | 58,555 | 2,528 | 4.2% | 287 |
| 1996 | 44,995 | 4.2% | 61,960 | 2,788 | 10.3% | 322 |
| 1997 | 46,819 | 4.1% | 62,038 | 2,905 | 4.2% | 333 |
| 1998 | 48,404 | 3.4% | 62,713 | 3,036 | 4.5% | 347 |
| 1999 | 49,430 | 2.1% | 64,186 | 3,173 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 66,043 | 3,310 | 4.3% | 383 |
| 2001 | 51,501 | 2.8% | 67,454 | 3,474 | 5.0% | 384 |
| 2002 | 52,915 | 2.7% | 64,719 | 3,425 | -1.4% | 390 |
| 2003 | 54,194 | 2.4% | 64,320 | 3,486 | 1.8% | 399 |
| 2004 | 55,577 | 2.6% | 63,898 | 3,551 | 1.9% | 407 |
| 2005 | 57,145 | 2.8% | 63,527 | 3,630 | 2.2% | 415 |
| 2006 | 59,050 | 3.3% | 63,487 | 3,749 | 3.3% | 427 |
| 2007 | 61,640 | 4.4% | 63,330 | 3,904 | 4.1% | 445 |
| 2008 | 63,492 | 3.0% | 62,249 | 3,952 | 1.2% | 451 |
| 2009 | 64,151 | 1.0% | 59,635 | 3,826 | -3.2% | 437 |
| 2010 | 64,421 | 0.4% | 58,851 | 3,791 | -0.9% | 434 |

## Commercial Load

### Projected Commercial Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 64,995 | 0.9% | 59,059 | 3,839 | 1.2% | 439 |
| 2012 | 66,265 | 2.0% | 58,734 | 3,892 | 1.4% | 445 |
| 2013 | 67,892 | 2.5% | 58,122 | 3,946 | 1.4% | 451 |
| 2014 | 69,600 | 2.5% | 57,471 | 4,000 | 1.4% | 457 |
| 2015 | 71,252 | 2.4% | 56,873 | 4,052 | 1.3% | 463 |
| 2016 | 72,840 | 2.2% | 56,204 | 4,094 | 1.0% | 468 |
| 2017 | 74,398 | 2.1% | 55,579 | 4,135 | 1.0% | 472 |
| 2018 | 75,950 | 2.1% | 54,977 | 4,176 | 1.0% | 477 |
| 2019 | 77,497 | 2.0% | 54,399 | 4,216 | 1.0% | 482 |
| 2020 | 79,031 | 2.0% | 53,841 | 4,255 | 0.9% | 486 |
| 2021 | 80,551 | 1.9% | 53,342 | 4,297 | 1.0% | 491 |
| 2022 | 82,058 | 1.9% | 52,929 | 4,343 | 1.1% | 496 |
| 2023 | 83,549 | 1.8% | 52,592 | 4,394 | 1.2% | 502 |
| 2024 | 85,030 | 1.8% | 52,307 | 4,448 | 1.2% | 508 |
| 2025 | 86,505 | 1.7% | 52,116 | 4,508 | 1.4% | 515 |
| 2026 | 87,976 | 1.7% | 52,022 | 4,577 | 1.5% | 523 |
| 2027 | 89,445 | 1.7% | 51,979 | 4,649 | 1.6% | 531 |
| 2028 | 90,906 | 1.6% | 52,057 | 4,732 | 1.8% | 541 |
| 2029 | 92,365 | 1.6% | 52,166 | 4,818 | 1.8% | 550 |
| 2030 | 93,823 | 1.6% | 52,363 | 4,913 | 2.0% | 561 |

## Irrigation Load

### Historical Irrigation Sales and Load,1970–2010

*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 7,319 | | 126,039 | 922 | | 105 |
| 1971 | 7,518 | 2.7% | 136,020 | 1,023 | 10.9% | 117 |
| 1972 | 7,815 | 4.0% | 131,163 | 1,025 | 0.2% | 117 |
| 1973 | 8,341 | 6.7% | 140,226 | 1,170 | 14.1% | 134 |
| 1974 | 8,971 | 7.6% | 147,179 | 1,320 | 12.9% | 151 |
| 1975 | 9,480 | 5.7% | 154,226 | 1,462 | 10.7% | 167 |
| 1976 | 9,936 | 4.8% | 152,340 | 1,514 | 3.5% | 172 |
| 1977 | 10,238 | 3.0% | 160,870 | 1,647 | 8.8% | 188 |
| 1978 | 10,476 | 2.3% | 152,800 | 1,601 | -2.8% | 183 |
| 1979 | 10,711 | 2.2% | 159,986 | 1,714 | 7.1% | 195 |
| 1980 | 10,854 | 1.3% | 154,900 | 1,681 | -1.9% | 191 |
| 1981 | 11,248 | 3.6% | 165,138 | 1,857 | 10.5% | 212 |
| 1982 | 11,312 | 0.6% | 150,370 | 1,701 | -8.4% | 194 |
| 1983 | 11,133 | -1.6% | 143,424 | 1,597 | -6.1% | 182 |
| 1984 | 11,375 | 2.2% | 131,427 | 1,495 | -6.4% | 170 |
| 1985 | 11,576 | 1.8% | 133,730 | 1,548 | 3.6% | 177 |
| 1986 | 11,308 | -2.3% | 134,686 | 1,523 | -1.6% | 174 |
| 1987 | 11,254 | -0.5% | 127,375 | 1,433 | -5.9% | 164 |
| 1988 | 11,378 | 1.1% | 136,257 | 1,550 | 8.2% | 176 |
| 1989 | 11,957 | 5.1% | 137,704 | 1,647 | 6.2% | 188 |
| 1990 | 12,340 | 3.2% | 144,106 | 1,778 | 8.0% | 203 |
| 1991 | 12,484 | 1.2% | 133,777 | 1,670 | -6.1% | 191 |
| 1992 | 12,809 | 2.6% | 139,469 | 1,786 | 7.0% | 203 |
| 1993 | 13,078 | 2.1% | 126,585 | 1,655 | -7.3% | 189 |
| 1994 | 13,559 | 3.7% | 128,848 | 1,747 | 5.5% | 199 |
| 1995 | 13,679 | 0.9% | 125,761 | 1,720 | -1.5% | 196 |
| 1996 | 14,074 | 2.9% | 123,537 | 1,739 | 1.1% | 198 |
| 1997 | 14,383 | 2.2% | 114,002 | 1,640 | -5.7% | 187 |
| 1998 | 14,695 | 2.2% | 112,933 | 1,660 | 1.2% | 189 |
| 1999 | 14,912 | 1.5% | 117,103 | 1,746 | 5.2% | 199 |
| 2000 | 15,253 | 2.3% | 125,903 | 1,920 | 10.0% | 219 |
| 2001 | 15,522 | 1.8% | 115,103 | 1,787 | -7.0% | 204 |
| 2002 | 15,840 | 2.0% | 109,768 | 1,739 | -2.7% | 198 |
| 2003 | 16,020 | 1.1% | 108,979 | 1,746 | 0.4% | 199 |
| 2004 | 16,297 | 1.7% | 106,547 | 1,736 | -0.5% | 198 |
| 2005 | 16,936 | 3.9% | 98,843 | 1,674 | -3.6% | 191 |
| 2006 | 17,062 | 0.7% | 96,848 | 1,652 | -1.3% | 189 |
| 2007 | 17,001 | -0.4% | 104,905 | 1,783 | 7.9% | 204 |
| 2008 | 17,428 | 2.5% | 108,350 | 1,888 | 5.9% | 215 |
| 2009 | 17,708 | 1.6% | 100,186 | 1,774 | -6.0% | 203 |
| 2010 | 17,846 | 0.8% | 99,148 | 1,769 | -0.3% | 202 |

## Irrigation Load

### Projected Irrigation Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 18,264 | 2.3% | 94,526 | 1,726 | -2.4% | 197 |
| 2012 | 18,541 | 1.5% | 93,518 | 1,734 | 0.4% | 197 |
| 2013 | 18,821 | 1.5% | 91,968 | 1,731 | -0.2% | 198 |
| 2014 | 19,101 | 1.5% | 90,686 | 1,732 | 0.1% | 198 |
| 2015 | 19,379 | 1.5% | 90,049 | 1,745 | 0.7% | 199 |
| 2016 | 19,655 | 1.4% | 89,212 | 1,753 | 0.5% | 200 |
| 2017 | 19,932 | 1.4% | 88,237 | 1,759 | 0.3% | 201 |
| 2018 | 20,212 | 1.4% | 87,324 | 1,765 | 0.4% | 201 |
| 2019 | 20,487 | 1.4% | 86,337 | 1,769 | 0.2% | 202 |
| 2020 | 20,767 | 1.4% | 85,426 | 1,774 | 0.3% | 202 |
| 2021 | 21,045 | 1.3% | 84,531 | 1,779 | 0.3% | 203 |
| 2022 | 21,323 | 1.3% | 83,591 | 1,782 | 0.2% | 203 |
| 2023 | 21,601 | 1.3% | 82,745 | 1,787 | 0.3% | 204 |
| 2024 | 21,878 | 1.3% | 81,991 | 1,794 | 0.4% | 204 |
| 2025 | 22,157 | 1.3% | 81,160 | 1,798 | 0.2% | 205 |
| 2026 | 22,437 | 1.3% | 80,269 | 1,801 | 0.2% | 206 |
| 2027 | 22,712 | 1.2% | 79,463 | 1,805 | 0.2% | 206 |
| 2028 | 22,988 | 1.2% | 78,494 | 1,804 | 0.0% | 205 |
| 2029 | 23,268 | 1.2% | 77,943 | 1,814 | 0.5% | 207 |
| 2030 | 23,547 | 1.2% | 77,079 | 1,815 | 0.1% | 207 |

## Industrial Load

### Historical Industrial Sales and Load, 1970–2010
*(weather-adjusted)*

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 49 | | 9,173,784 | 445 | | 52 |
| 1971 | 50 | 3.3% | 10,474,941 | 525 | 17.9% | 60 |
| 1972 | 56 | 12.1% | 10,944,714 | 615 | 17.2% | 71 |
| 1973 | 63 | 12.3% | 10,889,056 | 687 | 11.7% | 79 |
| 1974 | 65 | 2.2% | 11,464,249 | 739 | 7.6% | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,310,726 | 2,220 | -0.2% | 254 |

## Industrial Load

### Projected Industrial Sales and Load, 2011–2030

| Year | Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 2011 | 121 | -0.2% | 18,958,898 | 2,294 | 3.3% | 262 |
| 2012 | 125 | 3.3% | 18,768,661 | 2,346 | 2.3% | 268 |
| 2013 | 125 | 0.0% | 19,133,471 | 2,392 | 1.9% | 273 |
| 2014 | 126 | 0.8% | 19,320,558 | 2,434 | 1.8% | 278 |
| 2015 | 128 | 1.6% | 19,318,966 | 2,473 | 1.6% | 283 |
| 2016 | 131 | 2.3% | 19,155,425 | 2,509 | 1.5% | 286 |
| 2017 | 134 | 2.3% | 18,997,015 | 2,546 | 1.4% | 291 |
| 2018 | 134 | 0.0% | 19,256,620 | 2,580 | 1.4% | 295 |
| 2019 | 136 | 1.5% | 19,239,155 | 2,617 | 1.4% | 299 |
| 2020 | 139 | 2.2% | 19,087,337 | 2,653 | 1.4% | 302 |
| 2021 | 140 | 0.7% | 19,218,638 | 2,691 | 1.4% | 308 |
| 2022 | 142 | 1.4% | 19,241,280 | 2,732 | 1.5% | 312 |
| 2023 | 142 | 0.0% | 19,514,996 | 2,771 | 1.4% | 317 |
| 2024 | 145 | 2.1% | 19,391,910 | 2,812 | 1.5% | 321 |
| 2025 | 147 | 1.4% | 19,454,919 | 2,860 | 1.7% | 327 |
| 2026 | 148 | 0.7% | 19,673,262 | 2,912 | 1.8% | 333 |
| 2027 | 149 | 0.7% | 19,892,894 | 2,964 | 1.8% | 339 |
| 2028 | 152 | 2.0% | 19,876,216 | 3,021 | 1.9% | 344 |
| 2029 | 155 | 2.0% | 19,862,920 | 3,079 | 1.9% | 352 |
| 2030 | 156 | 0.6% | 20,124,445 | 3,139 | 2.0% | 359 |

## Additional Firm Sales and Load*

### Historical Additional Firm Sales and Load, 1970–2010

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 319 | | 36 |
| 1971 | 295 | -7.5% | 34 |
| 1972 | 284 | -3.7% | 32 |
| 1973 | 291 | 2.2% | 33 |
| 1974 | 282 | -2.9% | 32 |
| 1975 | 314 | 11.1% | 36 |
| 1976 | 277 | -11.8% | 31 |
| 1977 | 311 | 12.4% | 36 |
| 1978 | 357 | 14.9% | 41 |
| 1979 | 373 | 4.3% | 43 |
| 1980 | 360 | -3.4% | 41 |
| 1981 | 377 | 4.7% | 43 |
| 1982 | 367 | -2.5% | 42 |
| 1983 | 425 | 15.8% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 483 | 2.5% | 55 |
| 1987 | 503 | 4.2% | 57 |
| 1988 | 531 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | -6.8% | 71 |
| 1991 | 661 | 5.7% | 75 |
| 1992 | 681 | 3.0% | 78 |
| 1993 | 689 | 1.2% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,119 | -2.1% | 128 |
| 2002 | 1,139 | 1.8% | 130 |
| 2003 | 1,120 | -1.6% | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,176 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,142 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |
| 2009 | 965 | -13.4% | 110 |
| 2010 | 907 | -6.1% | 103 |

*Includes Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2011–2030**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 1,449 | 59.9% | 165 |
| 2012 | 1,627 | 12.3% | 185 |
| 2013 | 1,799 | 10.6% | 205 |
| 2014 | 1,902 | 5.7% | 217 |
| 2015 | 2,002 | 5.3% | 229 |
| 2016 | 2,071 | 3.4% | 236 |
| 2017 | 2,065 | -0.3% | 236 |
| 2018 | 2,070 | 0.2% | 236 |
| 2019 | 2,075 | 0.2% | 237 |
| 2020 | 2,073 | -0.1% | 236 |
| 2021 | 2,075 | 0.1% | 237 |
| 2022 | 2,082 | 0.3% | 238 |
| 2023 | 2,089 | 0.4% | 238 |
| 2024 | 2,096 | 0.3% | 239 |
| 2025 | 2,101 | 0.2% | 240 |
| 2026 | 2,112 | 0.5% | 241 |
| 2027 | 2,113 | 0.0% | 241 |
| 2028 | 2,119 | 0.3% | 241 |
| 2029 | 2,119 | 0.0% | 242 |
| 2030 | 2,125 | 0.3% | 243 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, "Special", and Raft River Rural Electric Cooperative, Inc.

## Company System Load (excluding Astaris)

### Historical Company System Sales and Load, 1970–2010
*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 3,915 | | 494 |
| 1971 | 4,279 | 9.3% | 539 |
| 1972 | 4,540 | 6.1% | 573 |
| 1973 | 5,027 | 10.7% | 634 |
| 1974 | 5,461 | 8.6% | 690 |
| 1975 | 6,001 | 9.9% | 758 |
| 1976 | 6,395 | 6.6% | 806 |
| 1977 | 6,817 | 6.6% | 858 |
| 1978 | 7,199 | 5.6% | 912 |
| 1979 | 7,766 | 7.9% | 976 |
| 1980 | 7,796 | 0.4% | 977 |
| 1981 | 8,066 | 3.5% | 1,015 |
| 1982 | 8,033 | -0.4% | 1,009 |
| 1983 | 8,009 | -0.3% | 1,012 |
| 1984 | 8,144 | 1.7% | 1,018 |
| 1985 | 8,367 | 2.7% | 1,053 |
| 1986 | 8,382 | 0.2% | 1,050 |
| 1987 | 8,434 | 0.6% | 1,056 |
| 1988 | 8,813 | 4.5% | 1,104 |
| 1989 | 9,257 | 5.0% | 1,164 |
| 1990 | 9,507 | 2.7% | 1,201 |
| 1991 | 9,740 | 2.5% | 1,218 |
| 1992 | 9,949 | 2.1% | 1,254 |
| 1993 | 10,237 | 2.9% | 1,275 |
| 1994 | 10,599 | 3.5% | 1,340 |
| 1995 | 11,045 | 4.2% | 1,375 |
| 1996 | 11,387 | 3.1% | 1,437 |
| 1997 | 11,669 | 2.5% | 1,469 |
| 1998 | 12,116 | 3.8% | 1,517 |
| 1999 | 12,461 | 2.8% | 1,564 |
| 2000 | 12,888 | 3.4% | 1,627 |
| 2001 | 13,022 | 1.0% | 1,592 |
| 2002 | 12,745 | -2.1% | 1,593 |
| 2003 | 13,000 | 2.0% | 1,633 |
| 2004 | 13,287 | 2.2% | 1,668 |
| 2005 | 13,571 | 2.1% | 1,703 |
| 2006 | 13,906 | 2.5% | 1,738 |
| 2007 | 14,336 | 3.1% | 1,795 |
| 2008 | 14,439 | 0.7% | 1,810 |
| 2009 | 13,933 | -3.5% | 1,746 |
| 2010 | 13,758 | -1.3% | 1,732 |

## Company System Load (including Astaris)

### Historical Company System Sales and Load, 1970–2010 (weather-adjusted) / Astaris Sales and Load (1970–2002)

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) | Astaris Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|---|---|---|
| 1970 | 5,572 | | 693 | 1,657 | | 189 |
| 1971 | 5,787 | 3.9% | 720 | 1,508 | -9.0% | 172 |
| 1972 | 6,359 | 9.9% | 791 | 1,819 | 20.6% | 207 |
| 1973 | 6,672 | 4.9% | 831 | 1,645 | -9.6% | 188 |
| 1974 | 7,105 | 6.5% | 887 | 1,643 | -0.1% | 188 |
| 1975 | 7,558 | 6.4% | 945 | 1,557 | -5.3% | 178 |
| 1976 | 7,970 | 5.5% | 995 | 1,575 | 1.2% | 179 |
| 1977 | 8,234 | 3.3% | 1,028 | 1,418 | -10.0% | 162 |
| 1978 | 8,741 | 6.2% | 1,097 | 1,542 | 8.8% | 176 |
| 1979 | 9,160 | 4.8% | 1,143 | 1,395 | -9.6% | 159 |
| 1980 | 9,309 | 1.6% | 1,157 | 1,513 | 8.5% | 172 |
| 1981 | 9,700 | 4.2% | 1,211 | 1,634 | 8.0% | 186 |
| 1982 | 9,587 | -1.2% | 1,195 | 1,554 | -4.9% | 177 |
| 1983 | 9,619 | 0.3% | 1,205 | 1,610 | 3.6% | 184 |
| 1984 | 9,845 | 2.4% | 1,221 | 1,701 | 5.7% | 194 |
| 1985 | 9,980 | 1.4% | 1,247 | 1,614 | -5.1% | 184 |
| 1986 | 9,935 | -0.5% | 1,236 | 1,554 | -3.7% | 177 |
| 1987 | 10,126 | 1.9% | 1,259 | 1,692 | 8.9% | 193 |
| 1988 | 10,448 | 3.2% | 1,300 | 1,635 | -3.4% | 186 |
| 1989 | 10,961 | 4.9% | 1,368 | 1,703 | 4.2% | 194 |
| 1990 | 11,111 | 1.4% | 1,394 | 1,604 | -5.8% | 183 |
| 1991 | 11,349 | 2.1% | 1,411 | 1,609 | 0.3% | 184 |
| 1992 | 11,519 | 1.5% | 1,442 | 1,570 | -2.4% | 179 |
| 1993 | 11,674 | 1.3% | 1,448 | 1,437 | -8.4% | 164 |
| 1994 | 12,019 | 3.0% | 1,510 | 1,420 | -1.2% | 162 |
| 1995 | 12,612 | 4.9% | 1,563 | 1,567 | 10.4% | 179 |
| 1996 | 13,076 | 3.7% | 1,639 | 1,689 | 7.8% | 192 |
| 1997 | 13,297 | 1.7% | 1,664 | 1,628 | -3.6% | 186 |
| 1998 | 13,389 | 0.7% | 1,670 | 1,273 | -21.8% | 145 |
| 1999 | 13,512 | 0.9% | 1,690 | 1,051 | -17.4% | 120 |
| 2000 | 13,942 | 3.2% | 1,753 | 1,054 | 0.3% | 120 |
| 2001 | 13,681 | -1.9% | 1,671 | 658 | -37.5% | 75 |
| 2002 | 12,757 | -6.8% | 1,594 | 11 | -98.3% | 1 |
| 2003 | 13,000 | 1.9% | 1,633 | 0 | -100.0% | 0 |
| 2004 | 13,287 | 2.2% | 1,668 | 0 | 0.0% | 0 |
| 2005 | 13,571 | 2.1% | 1,703 | 0 | 0.0% | 0 |
| 2006 | 13,906 | 2.5% | 1,738 | 0 | 0.0% | 0 |
| 2007 | 14,336 | 3.1% | 1,795 | 0 | 0.0% | 0 |
| 2008 | 14,439 | 0.7% | 1,810 | 0 | 0.0% | 0 |
| 2009 | 13,933 | -3.5% | 1,746 | 0 | 0.0% | 0 |
| 2010 | 13,758 | -1.3% | 1,732 | 0 | 0.0% | 0 |

## Company System Load

### Projected Company System Sales and Load, 2011–2030

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 14,521 | 5.5% | 1,819 |
| 2012 | 14,803 | 1.9% | 1,852 |
| 2013 | 15,093 | 2.0% | 1,890 |
| 2014 | 15,437 | 2.3% | 1,932 |
| 2015 | 15,751 | 2.0% | 1,970 |
| 2016 | 15,991 | 1.5% | 1,998 |
| 2017 | 16,174 | 1.1% | 2,023 |
| 2018 | 16,348 | 1.1% | 2,045 |
| 2019 | 16,545 | 1.2% | 2,070 |
| 2020 | 16,726 | 1.1% | 2,090 |
| 2021 | 16,898 | 1.0% | 2,114 |
| 2022 | 17,098 | 1.2% | 2,139 |
| 2023 | 17,313 | 1.3% | 2,166 |
| 2024 | 17,511 | 1.1% | 2,189 |
| 2025 | 17,694 | 1.0% | 2,214 |
| 2026 | 17,912 | 1.2% | 2,241 |
| 2027 | 18,084 | 1.0% | 2,263 |
| 2028 | 18,385 | 1.7% | 2,298 |
| 2029 | 18,606 | 1.2% | 2,329 |
| 2030 | 18,870 | 1.4% | 2,362 |

## Contract Off-System Load

### Historical Contract Off-System Sales and Load, 1970–2010

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 386 | | 44 |
| 1971 | 439 | 13.6% | 50 |
| 1972 | 448 | 2.0% | 51 |
| 1973 | 489 | 9.3% | 56 |
| 1974 | 501 | 2.3% | 57 |
| 1975 | 568 | 13.5% | 65 |
| 1976 | 613 | 7.9% | 70 |
| 1977 | 659 | 7.5% | 75 |
| 1978 | 684 | 3.7% | 78 |
| 1979 | 759 | 11.1% | 87 |
| 1980 | 762 | 0.3% | 87 |
| 1981 | 752 | -1.2% | 86 |
| 1982 | 736 | -2.2% | 84 |
| 1983 | 710 | -3.5% | 81 |
| 1984 | 747 | 5.2% | 85 |
| 1985 | 779 | 4.3% | 89 |
| 1986 | 670 | -13.9% | 77 |
| 1987 | 644 | -4.0% | 73 |
| 1988 | 675 | 4.9% | 77 |
| 1989 | 740 | 9.7% | 84 |
| 1990 | 968 | 30.8% | 111 |
| 1991 | 1,537 | 58.8% | 175 |
| 1992 | 1,348 | -12.3% | 154 |
| 1993 | 1,557 | 15.5% | 178 |
| 1994 | 1,811 | 16.3% | 207 |
| 1995 | 1,583 | -12.6% | 181 |
| 1996 | 1,285 | -18.8% | 146 |
| 1997 | 674 | -47.5% | 77 |
| 1998 | 716 | 6.2% | 82 |
| 1999 | 568 | -20.6% | 65 |
| 2000 | 587 | 3.3% | 67 |
| 2001 | 538 | -8.4% | 61 |
| 2002 | 454 | -15.7% | 52 |
| 2003 | 346 | -23.6% | 40 |
| 2004 | 19 | -94.4% | 2 |
| 2005 | 10 | -47.0% | 1 |
| 2006 | 0 | -100.0% | 0 |
| 2007 | 0 | 0.0% | 0 |
| 2008 | 0 | 0.0% | 0 |
| 2009 | 0 | 0.0% | 0 |
| 2010 | 0 | 0.0% | 0 |

### Projected Contract Off-System Sales and Load, 2011–2030

| | | | |
|---|---|---|---|
| 2011–2030 | 0 | 0.0% | 0 |

## Total Company Load

### Historical Total Company Sales and Load, 1970–2010
*(weather-adjusted)*

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 1970 | 5,958 | | 738 |
| 1971 | 6,226 | 4.5% | 772 |
| 1972 | 6,807 | 9.3% | 844 |
| 1973 | 7,162 | 5.2% | 889 |
| 1974 | 7,605 | 6.2% | 946 |
| 1975 | 8,126 | 6.8% | 1,012 |
| 1976 | 8,583 | 5.6% | 1,067 |
| 1977 | 8,894 | 3.6% | 1,106 |
| 1978 | 9,425 | 6.0% | 1,178 |
| 1979 | 9,920 | 5.2% | 1,233 |
| 1980 | 10,071 | 1.5% | 1,247 |
| 1981 | 10,453 | 3.8% | 1,300 |
| 1982 | 10,323 | -1.2% | 1,282 |
| 1983 | 10,329 | 0.1% | 1,289 |
| 1984 | 10,592 | 2.5% | 1,309 |
| 1985 | 10,759 | 1.6% | 1,339 |
| 1986 | 10,605 | -1.4% | 1,315 |
| 1987 | 10,770 | 1.5% | 1,335 |
| 1988 | 11,123 | 3.3% | 1,379 |
| 1989 | 11,701 | 5.2% | 1,455 |
| 1990 | 12,079 | 3.2% | 1,508 |
| 1991 | 12,886 | 6.7% | 1,592 |
| 1992 | 12,867 | -0.1% | 1,601 |
| 1993 | 13,231 | 2.8% | 1,632 |
| 1994 | 13,830 | 4.5% | 1,724 |
| 1995 | 14,195 | 2.6% | 1,750 |
| 1996 | 14,361 | 1.2% | 1,790 |
| 1997 | 13,971 | -2.7% | 1,744 |
| 1998 | 14,105 | 1.0% | 1,754 |
| 1999 | 14,081 | -0.2% | 1,757 |
| 2000 | 14,529 | 3.2% | 1,822 |
| 2001 | 14,219 | -2.1% | 1,735 |
| 2002 | 13,210 | -7.1% | 1,648 |
| 2003 | 13,347 | 1.0% | 1,674 |
| 2004 | 13,306 | -0.3% | 1,670 |
| 2005 | 13,581 | 2.1% | 1,704 |
| 2006 | 13,906 | 2.4% | 1,738 |
| 2007 | 14,336 | 3.1% | 1,795 |
| 2008 | 14,439 | 0.7% | 1,810 |
| 2009 | 13,933 | -3.5% | 1,746 |
| 2010 | 13,758 | -1.3% | 1,732 |

## Total Company Load

### Projected Total Company Sales and Load, 2011–2030

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (MW) |
|---|---|---|---|
| 2011 | 14,521 | 5.5% | 1,819 |
| 2012 | 14,803 | 1.9% | 1,852 |
| 2013 | 15,093 | 2.0% | 1,890 |
| 2014 | 15,437 | 2.3% | 1,932 |
| 2015 | 15,751 | 2.0% | 1,970 |
| 2016 | 15,991 | 1.5% | 1,998 |
| 2017 | 16,174 | 1.1% | 2,023 |
| 2018 | 16,348 | 1.1% | 2,045 |
| 2019 | 16,545 | 1.2% | 2,070 |
| 2020 | 16,726 | 1.1% | 2,090 |
| 2021 | 16,898 | 1.0% | 2,114 |
| 2022 | 17,098 | 1.2% | 2,139 |
| 2023 | 17,313 | 1.3% | 2,166 |
| 2024 | 17,511 | 1.1% | 2,189 |
| 2025 | 17,694 | 1.0% | 2,214 |
| 2026 | 17,912 | 1.2% | 2,241 |
| 2027 | 18,084 | 1.0% | 2,263 |
| 2028 | 18,385 | 1.7% | 2,298 |
| 2029 | 18,606 | 1.2% | 2,329 |
| 2030 | 18,870 | 1.4% | 2,362 |